drax

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Wholesale Market Reform team
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Non-confidential

Dear Wholesale Market Reform team,

Locational Pricing Assessment - Call for Input

Drax Group plc (Drax) owns and operates a portfolio of flexible, low carbon and renewable electricity generation assets – providing enough power for the equivalent of more than 8.3 million homes across the UK. The assets include Drax Power Station, based at Selby, North Yorkshire, which is the country's single largest source of renewable electricity. Drax also owns two retail businesses, Drax Energy Solutions (formerly trading as Haven Power) and Opus Energy, which together supply renewable electricity and gas to over 300,000 business premises.

We support the need for a detailed assessment of the potential benefits, costs and implementation requirements associated with transitioning to a zonal or nodal wholesale market design. We broadly agree with the modelling assumptions, methodology and potential wider policy impacts presented at the first stakeholder engagement workshop. In addition, we would highlight a number of high-level principles that we believe should apply:

- The case for change needs to be clearly established with a better-defined problem statement and an assessment of the scale of the issues that need to be resolved.

- Proportionality of measures and costs of implementation must be assessed against the potential benefits. Where the impacts are difficult to quantify, the assessment should highlight the range of uncertainties arising from the transition.

- The costs of implementation need to include all industry costs, including impacts on both the retail and the wholesale sector, cost of changing industry systems, frameworks, network codes and other relevant arrangements.

- Any assessment of costs and potential benefits / opportunities should be based on the specifics of the GB market supported by real market data, only citing international experiences that are comparable and applicable to the nature of the current GB market.

- Costs and benefits should consider dependencies on the timing of implementation, and the analysis should explore links and trade-offs with other ongoing reforms, such as the TNUoS Review.

The annex to this letter provides our views on the additional points that should be considered and reflected in the assessment approach.

Yours faithfully,

Matt Young

Group Head of Regulation

Drax Group Plc

Annex: Responses to Call for Input questions

1. The key opportunities associated with introducing more granular locational pricing in GB

We agree that, conceptually, nodal pricing can deliver certain benefits, such as operational efficiencies and system cost reductions. However, we are concerned that these benefits and opportunities may be overestimated based on theoretical assumptions and expectations of market behaviour. It is critical that Ofgem's assessment clearly explains where the benefits are predicated on assumptions such as consumer exposure to locational pricing signals.

Beyond the need to consider the underlying dependencies, it should be recognised that the benefit of moving to nodal pricing will depend on the timing of implementation, particularly where the case for change is materially based upon the reduction of constraints and congestion costs.

Overall, we believe that the rationale for the move to a nodal pricing market may over-prioritise constraint and congestion costs, and does not give equal or due consideration to more critical strategic objectives, such as system security and decarbonisation. The pros and cons of nodal pricing should be fairly considered in the context of achieving a market that delivers Net Zero, ensuring the design is future-proof and corresponds to wider decarbonisation goals both in the short and long term.

It will be important that the assessment considers whether the same improvement or benefits can be delivered more effectively via other routes, such as reforms to network codes, charging arrangements, improvements to network connectivity or changes to trading arrangements.

2. The key implementation challenges, risks and mitigations

The scale of the proposed change will make implementation challenging. Adequate notice and lead-times for implementation will be critical to ensure market participants can adopt the changes with as little disruption as possible.

We encourage Ofgem to consider all changes that will be required to existing frameworks, such as network codes, trading and settlement systems, ESO dispatch and balancing systems and other relevant arrangements. We are concerned with the potential complexity of future trading arrangements and the time and resource it will take to deliver the required systems, processes, training and testing for the new arrangements. Commercial and cost implications for all market participants, not just across retail and wholesale markets, must be adequately considered.

We're also concerned about the compound effect of any move to locational pricing along with the many reforms already underway, such as the TNUoS review, DUoS SCR, balancing services market reforms, a number of pending proposals for policy changes to the CM and CfD frameworks, as well as a myriad of reforms in the retail sector. The timing and sequence of the reforms needs to be carefully considered.

More generally, the transition to locational pricing, and associated uncertainty, may impact investor confidence leading to deferred investments and impact longer-term commitments from project developers. This may undermine progress towards decarbonisation targets. Uncertainty around fundamental market arrangements can be detrimental to larger-scale projects and investments, leading to security of supply and capacity adequacy risks in the future.

It will be important that the assessment considers how these risks may translate into consumer pricing both for large consumers as well as smaller domestic consumer groups. Impact on domestic and non-domestic suppliers needs to capture how pricing and tariff strategies may need to change in response to nodal design. As such, clarity around Financial Transmission Rights (FTRs) and their applicability and use in a specific GB market context will be critical.

Similarly, the risks associated with any transition may lead to a hiatus in network connections and network capacity build-out. It may also lead to speculative demand for access in specific locations with no intention or commitment of using this access in the future. This may result in delays in connections and higher costs to developers.

Another concern that needs to be addressed is the risk of market fragmentation and resulting market power of certain parties in certain locations. This needs to be considered in the context of competition, liquidity and the impact on the costs of CM contracts, CfDs and ancillary services.

3. The proposed approach to modelling zonal and nodal market designs

To answer this fully we've provided responses to the questions presented at the first engagement session.

Have we captured all the key impacts from transitioning to a locational market design? (Slide 15)

We broadly agree with the impacts highlighted in each category.

With regards to the short-run impacts, we note that the impact on ancillary services needs to be included, specifically potential increases in costs of ancillary services, such as reserve and stability services, as a result of 'missing-money' issues that may become more persistent for assets under a locational market design.

With regards to the long-run impacts, we note that the 'greater price signals for demand' benefit does not include consideration of the practicality of locational signals, such as dependencies on other sector developments and infrastructure, such as hydrogen, CCUS or availability of EV charging infrastructure. More generally, the impacts do not appear to explore the changing risk profile of existing and future projects and impacts on hurdle rates as a result.

The cost to market participants needs to be expanded to include impacts on all market participants, including across retail and wholesale markets, and costs arising from changes to market frameworks, network codes and industry systems.

The *Other policy interactions* category should elaborate on the interactions with other sectors and vectors of the energy industry, including Dispatchable Power Agreement (DPA) contract arrangements for hydrogen and CCUS projects.

Have we captured all relevant stakeholder groups and appropriately disaggregated (Slide 16)?

We agree with the categorisation of stakeholder groups, however, we question the level of granularity of this approach. In our view the proposed categories are too broad for use in any meaningful quantitative and qualitative assessments. For instance, we note that *Consumer* group can be interpreted to include domestic and non-domestic consumers as well as consumers with DSR capability and consumers with behind-the-meter generation. These sub-groups will have significantly different priorities and varying abilities to manage or absorb price impacts. Similarly, the *Storage/IC* group could include small-scale battery storage developers, as well as large-scale generators, with a materially different set of objectives, different market and locational options available to them, and differing appetite for investment risk.

We would recommend considering a level of granularity which reflects true operating and financing variations between different industry participants.

What are your views on the locational disaggregation we should model? (Slide 20-21)

We believe the main limitation of this approach is the focus on one model only, which may lead to a risk of choosing the wrong model and undermine the whole analysis. We would prefer to see all of the shortlisted models included in the comparison for completeness of the assessment.

What are your views on the scenarios we should model? (Slide 22)

We agree with the use of two FES 2021 scenarios - *Leading the Way* and *System Transformation* - as these are likely to be most reflective of the future system needed to deliver Net Zero.

What are your views on transmission post-2041? (Slide 27)

Option 1 would lead to an incomplete analysis and inconsistency in the assessment against Net Zero objectives. We believe it's important to have some modelling of the post-2041 system included. We support Option 2, which proposes to split the modelling into two periods, with our preference for the second period being based on an endogenous build-out.

What are your views on how generation capacity should be forecasted? (Slide 30-31)

We agree with the need for a more detailed modelling approach with a more granular regional split. We believe that the model should produce locational mixes for both pricing systems, and the status quo should include the existing locational signals such as TNUoS charges.

With regards to generation capacity forecasts, we are keen to see consistency between the hourly profiles that the model will return. It is also important to ensure ENTSO-E or other EU data is applied correctly to the GB market, taking into account specific environmental, weather and regional variations. Similarly, siting of generation in response to price signals will be highly dependent on local environmental laws, planning rules and availability of connection capacity. This needs to be reflected accordingly.

We broadly agree with the proposed approach to modelling demand. However, we note that the last step in this approach, i.e. assessing impacts of demand portability, is absolutely critical but currently lacks any detail. In our view, the level of expected demand response, which is the underlying success factor of the nodal design, is highly dependent on portability and flexibility of demand. This includes dependencies based on the build-out of hydrogen and CCUS infrastructure as well as the development of decarbonised heat and transport sectors. A critical, realistic and not overly optimistic assessment of portability will be key to ensuring any benefits are achievable and not overstated.

In relation to modelling commodity prices, we note a possible error in the second graph on slide 32, where the reference to Gas price forecasts is expressed in €/tCO2.

What are your views on our approach to modelling CfD contract holders? (Slide 36)

Our main concern is that the approach to assessing the impact of CFDs, which feeds into the main modelling exercise, does not include the impact on DPA or equivalent contracts for CCUS and hydrogen. These may have the ability to alter the merit order and dilute any locational signals, and should be considered in the modelling approach.

What are your views on the potential impacts of locational pricing on the cost of capital? (Slide 37)

In our view the key risk to investors lies in the uncertainty of future market arrangements. In the near-term this may lead to deferred investments, leading to capacity adequacy and decarbonisation issues in the future. The longer-term uncertainty with locational variations, inability to de-risk longer-term contracts, and lack of certainty around future hurdle rates may significantly undermine investor confidence.

While we agree that a reduced TNUoS volatility may lower the risks for developers, the impact of overall TNUoS charges, their volatility and their predictability, currently varies between projects impacting project viability. As such, offshore wind projects and projects based in zones further away from the demand-weighted node, find the impact of TNUoS to be important, while for other projects it can be relatively immaterial. Generally, the impact of TNUoS volatility on the overall risk profile of a project should be assessed on a case-by-case basis.

What are your views on (1) our proposed sensitivities; and (2) other sensitivities we should include; and (3) which sensitivity is a high priority? (Slide 39)

We agree with both sensitivities outlined in Part A, i.e. *Locational price exposure to demand* and *Impact of nodal pricing on dispatch*. We believe these are critical sensitivities to run, and if the model has the capability to do so, it should include both sensitivities in the analysis.

In Part B, our view is that *Generation and transmission sensitivities*, specifically looking at variations in GB nuclear and Interconnector capacity, should be prioritised.

Notwithstanding that, all of the sensitives identified in this section have a critical impact on the forecasts and modelling of future capacity, demand levels and dispatch, therefore, the analysis should aim to include all of them.

Have we missed any policies that would likely be impacted by the introduction of more granular locational pricing? (Slide 43)

Our main concern with the proposed model is that it doesn't include re-dispatch. We believe all ESO services, including its role as a residual balancer and system operator should be included in the modelling to give a true reflection of the future market dynamics. Including ancillary services and re-dispatch model in the analysis will provide a more complete and accurate representation of the merit order, capacity availability and system flows.